Application 22-05-002 (cons)
Exhibit No.: IPC-02

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027.	**Application 22-05-002 (Filed May 2, 2022)**
And Related Matters.	**Application 22-05-003** **Application 22-05-004**

Prepared Rebuttal Testimony of

Robert R. Stephens

On behalf of

Industrial Pumping Customers

May 12, 2023

Brubaker & Associates, Inc.

Project 11469

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Prepared Rebuttal Testimony of Robert R. Stephens

Introduction/Summary

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME ROBERT R. STEPHENS WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A Yes. I filed Direct Testimony on April 21, 2023 on behalf of Industrial Pumping Customers ("IPC").

Q WHAT IS THE SUBJECT MATTER OF YOUR REBUTTAL TESTIMONY?

A My testimony responds to the testimonies of certain other witnesses as they relate to the Base Interruptible Program ("BIP"), a Demand Response ("DR") offering by SCE. Specifically, I will respond to the Direct Testimony of Sam Harper on behalf of California Large Energy Consumers Association ("CLECA"), Opening Testimony of Joint Demand

Response Parties' witnesses Jennifer A. Chamberlin and Poonum Agrawal, Opening Testimony of Public Advocates Office ("Cal Advocates") witnesses S. Castello, P. Koenig and K. Tran, and Prepared Testimony of Enchanted Rock, LLC witness Scott D. Lipton, as these testimonies relate to BIP incentive levels.

My silence on any other aspect of any party's testimony in this case should not be construed as agreement with same.

Q PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A My testimony can be summarized as follows:

- As I indicated in my Direct Testimony, BIP is an important resource to help maintain grid reliability, and BIP enrollment has been in decline since 2019. DR is needed more than ever, and the incentive levels for participation need to be substantial and sufficient to make the program worthwhile for participation.

- Other parties commenting on BIP incentive levels, including CLECA, Joint Demand Response Parties, and Enchanted Rock, LLC, recognize the need to increase BIP incentives as well. In contrast, Cal Advocates opposes additional BIP spending by SCE.

- Regarding the differences between the BIP incentives for Sub-transmission voltage customers and Primary and Secondary voltage customers, I recommend Sub-transmission incentive levels that differ from the Primary voltage incentive levels by only the difference in line losses.

- IPC companies in this matter express the potential to increase participation and the need to ensure adequate incentive for maintaining current IP participation.

Response to CLECA Witness Harper

Q HAVE YOU REVIEWED THE DIRECT TESTIMONY OF CLECA WITNESS HARPER AS IT RELATES TO BIP INCENTIVES?

A Yes, I have. Mr. Harper's testimony is directed principally at BIP. In addition to seeking higher incentive levels, he advocates for other program design changes intended to facilitate customers' participation in the BIP. I generally support the program design changes that will make BIP more attractive. However, my focus is on the SCE BIP incentive levels, which he addresses at pages 16 through 19 of his testimony.

Q AT PAGE 17, MR. HARPER STATES THAT "SCE'S AND PG&E'S PROPOSED INCREASES ARE MODEST CONSIDERING RELIANCE ON BIP TO MAINTAIN GRID RELIABILITY, AND THE PARADIGM SHIFT IN USAGE IS LIKELY TO CONTINUE." HOW DO YOU RESPOND?

A I agree. Regarding SCE, not only are the proposed BIP incentive increases modest, but they do not reflect the dramatic increase in value of capacity reported by SCE in its March 2023 Supplemental Testimony. I address this at pages 4 through 6 of my Direct Testimony. Mr. Harper references the same large increase.[1]

Q AT PAGE 18 OF HIS TESTIMONY, MR. HARPER STATES THAT "CURRENT AND POTENTIAL NEW BIP CUSTOMERS WILL HAVE TO WEIGH THE IMPACT ON THE BUSINESS OF MODESTLY INCREASED INCENTIVES COMPARED TO DRAMATICALLY HIGHER CURTAILMENTS." HOW DO YOU RESPOND?

A I agree with Mr. Harper that participants have to weigh the potential benefits of the program, through incentive payments, against the potential costs to their businesses of being interrupted. To the extent expected curtailments increase, as is likely the case, this will require significantly higher incentives to offset the increasing cost element.

[1]Exhibit CLECA-01 at page 17.

Q AT PAGES 18 THROUGH 19, MR. HARPER PROPOSES A SMALL BIP INCENTIVE FOR "ALL OTHER HOURS," I.E., HOURS WHICH DO NOT PRESENTLY RECEIVE INCENTIVES, TO REFLECT THAT BIP CUSTOMERS COMMIT TO CURTAIL ALL HOURS OF THE DAY, EVERY DAY OF THE YEAR. HOW DO YOU RESPOND TO THIS PROPOSAL?

A I think a modest incentive in these hours is reasonable. This addition has the potential to make BIP somewhat more economically viable and acceptable to customers.

Response to Joint Demand Response Parties Witnesses Chamberlin and Agrawal

Q HAVE YOU REVIEWED THE TESTIMONY OF JOINT DEMAND RESPONSE PARTIES' WITNESSES CHAMBERLIN AND AGRAWAL, AS THAT TESTIMONY RELATES TO SCE'S BIP INCENTIVE LEVELS?

A Yes, I have. The witnesses address BIP at pages 17 through 24 of their testimony.

Q AT PAGE 18, THE WITNESSES STATE THAT "IN ORDER TO AVOID ANY PROGRAM ATTRITION AND TO MEET ENROLLMENT PROJECTIONS, INCENTIVE RATES FOR BOTH PG&E AND SCE NEED TO BE INCREASED TO ENTICE CUSTOMERS AND ENSURE STRONG PERFORMANCE FROM LARGER CUSTOMERS." HOW DO YOU RESPOND?

A I strongly support this assessment, as I have indicated in my Direct Testimony, and earlier in this testimony. Unless the incentives are perceived by customers to be sufficient to overcome the expected cost of curtailment, attrition will occur, at a time when utilities should be building up the BIP resource, not allowing it to diminish. The witnesses highlight this as it relates to the 50+ kV customers, at page 19, stating, "the significantly lower incentive rate for 50 + kV customers may not continue to meet many of these customers' cost to curtail," suggesting that an incentive rate for these customers that is more closely aligned with the other two lower voltage incentive categories would help ensure continued strong performance and participation from the customers in the 50+ kV category. This discrepancy between the lower voltage customers and the Sub-transmission (or 50+ kV) customers is unexplained in SCE's testimony, as I noted in my Direct Testimony.[2] The 5% to 10% variance suggested by these witnesses is reasonable, to the extent it reflects differences in line losses, which are a legitimate factor for differing BIP incentive levels.

It is important to maintain adequate incentive levels for the 50+ kV customers, as these customers[3] provide significant contributions to the BIP. SCE should be very careful not to undervalue the incentives to this customer group.[4]

Q AT PAGE 20, THE JOINT DEMAND RESPONSE PARTIES' WITNESSES PROVIDE A TABLE INDICATING THEIR PROPOSED INCENTIVE RATES FOR SCE'S BIP. WHAT IS YOUR RESPONSE TO THEIR PROPOSAL?

A If one compares the table on page 20 to the proposed BIP credits on page 19, it is evident that the proposed incentive rates for the 50+ kV Sub-transmission service customers would be identical to the Secondary service customers. I do not believe the incentives for Sub-transmission service should be identical to Secondary voltage service, due to the line loss differences, though they should be much closer than what SCE has proposed. The difference should be only a few percentage points, as I indicated in my Direct Testimony.[5]

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[2]Exhibit IPC-01 at page 7.

[3]This is shown by SCE in its Response to Data Request IPC-SCE-01, Question 02(b), included in Exhibit RRS-2.

[4]I note that PG&E's BIP incentives are higher for larger customers. See Cal. P.U.C. Sheet No. 52773-E.

[5]Exhibit IPC-01 at page 6.

As I indicated in my Direct Testimony, in addition to updating the incentive levels for all three voltage classes, SCE should significantly reduce the discrepancy between the Sub-transmission incentive levels and the Secondary and Primary incentive levels, as Joint Demand Response Parties acknowledge.

Q DO YOU HAVE A RECOMMENDATION REGARDING THE SUB-TRANSMISSION VOLTAGE INCENTIVES?

A Yes. The incentives should be the same as the Primary voltage incentive levels, adjusted only for differences in line losses. The line loss adjustment factors for Primary and Sub-transmission voltage service are 1.06958 and 1.01653, respectively.[6] Thus, the Sub-transmission voltage incentives are straightforward and logically calculated by multiplying the respective Primary voltage incentives by the ratio 1.01653/1.06958, or 0.950 (95.0%).

Q GIVEN THE PROPOSED INCREASES IN BIP INCENTIVE BY SCE AND PG&E, IS THERE ADDITIONAL INFORMATION WHICH SHOULD BE CONSIDERED IN ADJUSTING THE SUB-TRANSMISSION INCENTIVES TO REFLECT THE BENFIT PROVIDED?

A Yes, the CPUC and the State have taken extraordinary measures to ensure adequate capacity:

- PG&E has been authorized to seek an extension of the operation of the Diablo Canyon Nuclear Power Plant for the 5 years of 2025 through 2030.[7]

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[6]From SCE's Response to Data Request IPC-SCE-001, Question 02, attachment "DR Billing Incentive Factors (Workpapers).xlsx, Column P, included in Exhibit RRS-2.

[7] See, Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) (requiring the Commission to consider the potential extension of operations at the Diablo Canyon Nuclear Power Plant); Decision (D.) 22-12-005, *Decision Implementing Senate Bill 846*, Application 16-08-006, Dec. 6, 2022 at Ordering Paragraph 2 ("[PG&E] is authorized and directed to take all of the actions identified in this decision, and any other actions that would be necessary, to operate Diablo Canyon power plant Units 1 and 2 beyond

- 5 GW Strategic Reserve being implemented in with 2.8 GW of Once through Cooling NG Generators being extended a second time for three years for 2024 through 2026.[8]

We don't believe these extraordinary measures are reflected in SCE Demand Response program's Sub-transmission incentives for 2024 through 2027.

Q CAN YOU REFERENCE SPECIFIC ADDITIONAL LOAD WHICH WOULD BE AVAILABLE TO ADD, SHOULD THE SUB-TRANSMISSION INCENTIVE BE INCREASED?

A Yes, the IPC companies represented would consider adding a substantial amount of interruptible load, in addition to maintaining their existing significant load on the BIP program.

Response to Cal Advocates Witnesses Castello, Koenig and Tran

Q HAVE YOU REVIEWED THE OPENING TESTIMONY OF CAL ADVOCATES WITNESSES CASTELLO, KOENIG AND TRAN AS RELATES TO SCE'S BIP?

A Yes, I have. The witnesses do not address the incentive levels, per se, and their discussion of the SCE BIP program is relatively short.[9] In this section, the witnesses oppose certain costs related to the IP billing system upgrades and SCE's proposed $14.9 million increase to the incentive paid to commercial customers.[10]

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the current federal license expiration dates, so as to preserve the option of extended operations until the following retirement dates. . .")

[8] Assembly Bill (AB) 205 (Chapter 61, 2022), later modified by AB 209 (Chapter 251, 2022)

[9]See Cal Advocates Testimony at pages 2-8 through 2-9.

[10]Id. at page 2-8.

Q ARE YOU CONCERNED WITH THE CAL ADVOCATES TESTIMONY IN REGARD TO SCE'S BIP INCENTIVES?

A No. My understanding is that SCE's incentives are based primarily on the avoided generation capacity costs. Consequently, the focus is more on the capacity cost basis for the incentive.

Unfortunately, the witnesses oppose reliance on the updated cost-effectiveness scores presented in the March 2023 supplemental testimony.[11] Ignoring the updated avoided capacity values would be problematic, as relates to BIP incentive levels, since the avoided capacity cost information from May 2022 is already outdated, and is key to setting the BIP incentive levels. Consequently, I recommend this recommendation of Cal Advocates be rejected, to the extent it affects BIP incentive levels.

Response to Enchanted Rock, LLC Witness Lipton

Q HAVE YOU REVIEWED THE PREPARED TESTIMONY OF SCOTT D. LIPTON, AS IT RELATES TO BIP INCENTIVE LEVELS?

A Yes, I have. BIP matters are the focus of Mr. Lipton's testimony. However, although Mr. Lipton's testimony is related to PG&E's BIP program, he does identify some concepts that are more broadly applicable.

Q PLEASE PROVIDE AN EXAMPLE OF SUCH A CONCEPT.

A At page 4 of his testimony, Mr. Lipton states that "higher BIP participation levels in turn will provide CAISO with a larger pool of resources upon which it can call for firm and reliable and demand response services." I agree with this assertion and indicated a

[11] Id. at pages 1-4 through 1-5.

similar concept in my direct testimony.[12] The goal is, or should be, maximizing the BIP resource, along with other DR resources, as long as the capacity situation remains tight.

Conclusion

Q WAS THIS MATERIAL PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A Yes, it was.

Q INSOFAR AS THIS MATERIAL IS FACTUAL IN NATURE, DO YOU BELIEVE IT TO BE CORRECT?

A Yes, I do.

Q INSOFAR AS THIS MATERIAL IS IN THE NATURE OF PROFESSIONAL OPINION OR JUDGMENT, DOES IT REPRESENT YOUR BEST PROFESSIONAL OPINION OR JUDGEMENT?

A Yes, it does.

Q DO YOU ADOPT THIS TESTIMONY AS YOUR SWORN TESTIMONY IN THESE CONSOLIDATED PROCEEDINGS?

A Yes.

Q DOES THIS CONCLUDE YOUR PREPARED REBUTTAL TESTIMONY?

A Yes, it does.

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[12]Exhibit IPC-1 at page 9.

Southern California Edison
A.22-05-002, A.22-05-003, A.22-05-004 – 2023-2027 Demand Response Application

DATA REQUEST SET I P C - S C E - 0 0 1

To: ICP
Prepared by: Emrah Ozkaya
Job Title: BIP Program Advisor
Received Date: 4/17/2023

Response Date: 5/1/2023

Question 02:
"In reference to Exhibit No. SCE-04, page 7, Table II-3, please provide the following information with respect to the proposed BIP credits:

a. A comprehensive narrative explanation for the proposed credits, by time period and voltage level, for both the 15-minute option and the 30-minute option.

b. Workpapers (executable versions in native format with all formulas intact) supporting the proposed credits for each time period and voltage level for both the 15-minute option and the 30-minute option."

Response to Question 02:

As a general matter, SCE objects to the extent the data request (i) seeks the production of information that is not relevant to the subject matter involved in the pending proceeding nor reasonably calculated to lead to such relevant information (Commission Rule 10.1; Cal. Code Civ. P. 2017.010); (ii) would require SCE to create any new document or other material in order to respond (Commission Rule 10.1; Cal. Code Civ. P. 2017.010); and/or (iii) is overly broad and/or the burden and expense of responding to the request outweigh the likelihood that the information sought will lead to the discovery of admissible evidence (Commission Rule 10.1; Cal. Code Civ. P. 2017.020).

Subject to those objections, SCE provides in response the attached documents providing an explanation of how BIP incentives are calculated, and workpapers supporting the calculations.

A well-designed incentive structure should accurately reflect the expected benefit a DR program may provide, in the form of avoided cost, while accounting for the relative program deployment constraints. Participation in DR programs results in avoided cost of generation capacity, which is a key determinant of value when deriving the appropriate level of incentives to encourage participation in such programs. Consistent with the Commission's DR Cost Effectiveness Protocols[1], SCE proposed to use the Avoided Cost Methodology to set program incentives for the 2024–2027 program cycle for the Agricultural & Pumping Interruptible (AP-I), Base Interruptible Program (BIP), and Summer Discount Plan (SDP) programs described in Exhibit SCE-03. Because 2023 is a bridge fund year, incentive rates for 2023 will remain the same as in 2022 as described in SCE-02. The resulting incentives are incorporated into SCE's TOU-AP-I and TOU-BIP rate schedules. The initial input for this methodology is an avoided generation capacity value, which SCE proposed to align with the generation capacity value adopted in its 2021 GRC Phase 2 proceeding,[2] as it has done in past DR application cycles. This approach ensures that the inputs used to calculate incentives for SCE's DR programs correspond with the generation capacity value used to derive SCE's retail rates.

Consistent with the Commission's Protocols, SCE's incentive calculation uses an avoided cost methodology whereby the avoided generation capacity value is adjusted using A and B factors (detailed below) that compare the program resource value to a four-hour lithium-ion battery proxy resource.

The A-factor used demand response program incentive calculation adjusts for event duration, call frequency, and total callable program hours. This method has been consistently applied to incentive design for DR programs since SCE's 2009 GRC Phase 2 proceeding, and appropriately values the efficacy of the different DR programs in comparison to a hypothetical marginal generation capacity resource. For example, a DR program with unlimited calls and unlimited frequency of occurrence would have an A-factor of 100%, reflecting that a program with these parameters should have a comparable resource value as the marginal generation resource.

SCE uses a Capacity Allocation Tool (CAT) to determine which hours in the calendar year SCE's grid is most likely to face a 1-in-10 capacity shortfall event. The 1-in-10 standard is a common reliability metric that strikes the appropriate balance between procuring enough capacity so that shortfall events are uncommon, but not too much capacity that procurement becomes cost prohibitive while adding little additional value to grid reliability. The CAT performs a Monte Carlo simulation considering load, wind, and solar and compares the resulting net load to the available resources with their associated outages to determine the likelihood of a capacity shortfall event on any given hour in a month. The final output of the CAT is a dataset that represents the hours in the year with the highest probability of a 1-in-10 capacity shortfall event occurring. Using this dataset, SCE allocates the generation capacity cost to the expected hours of system capacity constraints. SCE proposed a similar framework in its 2021 GRC Phase 2 application, filed on October 1, 2020. The resulting allocation of generation capacity costs is an input when determining the individual A-Factors assigned to specific DR programs. The A-Factor represents the ability of DR programs to cover the expected 1-in-10 capacity shortfall events resulting from the CAT. Using this methodology, a DR program will be assigned a higher A-Factor if the program is expected to mitigate more potential shortfall events based on the program's

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[1] See D.15-11-042, Decision Addressing the Valuation of Load Modifying Demand Response and Demand Response Cost-Effectiveness Protocols; id., Appendix A, 2015 Demand Response Cost Effectiveness Protocols; D.16-06-007, Decision to Update Portions of the Commission's Current Cost-Effectiveness Framework.

[2] In its 2021 GRC Phase 2 proceeding, SCE and intervening parties settled on a generation capacity value of $100/kW-year. To the extent a different capacity value is ultimately adopted in its 2021 GRC Phase 2 proceeding, SCE proposes updating the generation capacity value used to determine program incentives in this proceeding.

duration and frequency of availability. For example, if Programs X and Y can be dispatched twice in a year, but Program X is available for three hours longer, then Program X will likely be assigned a higher A-Factor than Program Y.

The B-factor represents the value of a DR program to be dispatched with day-of versus day-ahead notification. A DR program with day-of notification has a "B" factor value of one (1), and DR programs with day-ahead notification would be assigned a value of less than 1. In addition to the A- and B-Factors described above, the avoided capacity cost is adjusted for the fact that DR programs are counted toward SCE's Planning Reserve Margin (PRM) in SCE's Resource Adequacy (RA) filings. SCE applies a nine percent reserve valuation adder to the avoided cost to accurately reflect the PRM value[3]. The methodology described above can be formulaically expressed as:

$$\textit{DR Program Avoided Cost} = \textit{Avoided Generation Capacity Cost} * (A * B + PRM) + \textit{Distribution Reliability Adder}$$

For the purposes of incentive valuation, SCE uses forecasted enrollments and ex ante estimates that are forward-looking and reflect the potential load reduction given a 1-in-10 peak capability scenario of DR program dispatch. SCE's A-factor used in the incentive design values the efficacy of DR programs for a potential 1-in-10 system reliability event. Aligning the estimate of expected demand with the same 1-in-10 criteria allows a consistent application of the valuation criteria used when determining overall incentives at the program level. Annual DR Program incentives are calculated using the following formula.

$$\textit{DR Program Annual Incentive Value} = \textit{DR Program Avoided Cost} * \textit{Expected Demand}$$

When designing the incentive rate structure for DR programs, where possible, SCE attempts to align the structure of the incentive with the applicable retail tariffs specific to the rate group. This alignment serves to: (1) facilitate customer understanding of the incentive as it mimics the tariff structure, and (2) promote equity on a per-customer basis in a manner that aligns incentive payouts with the recovery of generation costs in rates. Line losses and time of use (TOU) periods form essential components when designing incentive structure for DR programs and aligning these structures with the retail rates.

For customers taking service at different service voltages, the avoided generation-level cost value is adjusted to reflect the estimate of line losses for each service voltage. In its DR Application, SCE proposed to use the line losses calculation proposed in SCE's 2021 GRC Phase 2 proceeding. The resulting DR program avoided costs, adjusted for service voltage line losses, are derived using the following formula:

$$\textit{Adjusted DR Program Avoided Cost}_{\textit{Service Voltage}} = \textit{DR Program Avoided Cost} * (1 + \textit{Line Losses}_{\textit{Service Voltage}})$$

TOU periods used in the design of the incentive rate structure for each DR program are based on SCE's current TOU periods.

In summary, when designing the rate structure for DR incentives, SCE follows a methodical framework of first valuing annual program incentive levels based on DR program avoided capacity cost and subsequently conveying this value to program participants based on a structure that is aligned with the default applicable tariff and TOU periods.

[3] See D.21-06-029, p. 41.

It's worth noting that current BIP incentives include a 20% adder that was adopted in the 2021 Reliability OIR whereas SCE's proposed incentives, starting in 2024, do not include this adder.

Recorded Average (2019,2020,2021)								Load Impact MW					DR adjusted Avoided Cost $/kW-yr	Line losses		DR adjusted Avoided Cost $/kW-yr
Customer	BIP Type	Rate Group	kVL	Interruptible MW	Average Summer On-MW	Average Summer Mid-MW	Average Winter Mid-MW	2024	Avoided Cost $/kW-yr	A factor	B factor	PRM	= AC * (A * B + PRM)	**2021 GRC**		**adjusted for losses**
												9.00%				
BUNDLED	15MIN	TOU-GS-3	SEC	2	2	0	3							**1.11004**		$116.00
BUNDLED	15MIN	TOU-8-SEC	SEC	6	13	5	22							1.11004		$116.00
BUNDLED	15MIN	TOU-8-PRI	PRI	12	30	22	50							**1.06958**		$111.77
BUNDLED	15MIN	TOU-8-SUB	SUB	127	341	341	674							**1.01653**		$106.23
DA/CCA	15MIN	TOU-GS-3	SEC	0	1	0	1							1.11004		$116.00
DA/CCA	15MIN	TOU-8-SEC	SEC	3	6	3	10							1.11004		$116.00
DA/CCA	15MIN	TOU-8-PRI	PRI	9	21	19	41							1.06958		$111.77
DA/CCA	15MIN	TOU-8-SUB	SUB	68	163	167	317							1.01653		$106.23
				228	577	558	1,117	182.1		95.50%	100.00%	9.00%	**$104.50**			
BUNDLED	30MIN	GS-2	SEC	0	0	0	0							1.11004		$116.00
BUNDLED	30MIN	TOU-GS-3	SEC	8	9	4	14							1.11004		$116.00
BUNDLED	30MIN	TOU-GS-3	PRI	1	1	1	2		**$100.00**					1.06958		$111.77
BUNDLED	30MIN	TOU-GS-3	SUB	7	10	11	14							1.01653		$106.23
BUNDLED	30MIN	TOU-8-SEC	SEC	82	158	64	251							1.11004		$116.00
BUNDLED	30MIN	TOU-8-PRI	PRI	73	114	87	199							1.06958		$111.77
BUNDLED	30MIN	TOU-8-SUB	SUB	119	190	142	322							1.01653		$106.23
DA/CCA	30MIN	TOU-GS-3	SEC	6	7	2	10							1.11004		$116.00
DA/CCA	30MIN	TOU-8-SEC	SEC	39	75	44	120							1.11004		$116.00
DA/CCA	30MIN	TOU-8-PRI	PRI	41	88	52	149							1.06958		$111.77
DA/CCA	30MIN	TOU-8-SUB	SUB	77	210	203	409							1.01653		$106.23
				452	862	610	1,490	352.5		95.50%	100.00%	9.00%	**$104.50**			
	30MIN															
BUNDLED	AGG	TOU-GS-3	SEC	0	1	0	1									
BUNDLED	AGG	TOU-8-SEC	SEC	3	6	3	9									
BUNDLED	AGG	TOU-8-PRI	PRI	3	2	0	6									
DA/CCA	AGG	GS-2	SEC	0	0	0	0									
DA/CCA	AGG	TOU-GS-3	SEC	0	1	0	1									
DA/CCA	AGG	TOU-8-SEC	SEC	2	3	2	5									
DA/CCA	AGG	TOU-8-PRI	PRI	0	0	0	0									
DA/CCA	AGG	TOU-8-SUB	SUB	16	44	43	101									
				24	57	49	122									

#REF!		$000	$000
2024		Estimated Test Year Incentives	**Estimated Test Year Incentives by season**
1.6		$181	
4.8		$552	
9.7		$1,088	
101.8		$10,816	
0.2		$23	
2.7		$314	
6.9		$769	
54.4		$5,783	
182.1		**$19,526**	
0.2		$19	
6.2		$722	
0.7		$74	
4.8		$515	
63.0		$7,304	
55.8		$6,236	
87.8		$9,328	
4.5		$518	
30.6		$3,552	
30.1		$3,370	
68.8		$7,309	
352.5		**$38,946**	

Estimated Test Year Incentives by season	Season	Average TOU demand - MW	Proposed - $/Average kW demand/month				Proposed $/Average kW demand/month					
$13,186	**SEC**			15MIN	30MIN		**30MIN**		**15MIN**		15MIN	30MIN
$8,108	Summer On	281	(28.84)	($616)	($7,492)	$375	(27.40)	($7,118)	($669)	(31.35)	21.4	259.8
$850	Summer Mid	129	(6.61)	($61)	($789)	$39	(6.28)	($749)	($67)	(7.18)	9.3	119.3
$4,228	Winter Mid	446	(9.49)	($338)	($3,890)	$195	(9.01)	($3,696)	($367)	(10.31)	35.6	410.1
$11,536	**PRI**			15MIN	30MIN		**30MIN**		**15MIN**		15MIN	30MIN
$7,094	Summer On	257	(27.65)	($1,411)	($5,683)	$284	(26.27)	($5,399)	($1,534)	(30.06)	51.0	205.5
$744	Summer Mid	181	(4.10)	($168)	($575)	$29	(3.90)	($547)	($183)	(4.46)	41.0	140.3
$3,699	Winter Mid	447	(8.28)	($748)	($2,951)	$148	(7.87)	($2,803)	($813)	(9.00)	90.4	356.4
$33,750	**SUB**			15MIN	30MIN		**30MIN**		**15MIN**		15MIN	30MIN
$20,753	Summer On	958	(21.65)	($10,919)	($9,834)	$492	(20.57)	($9,342)	($11,871)	(23.54)	504.3	454.1
$2,175	Summer Mid	907	(2.40)	($1,218)	($957)	$48	(2.28)	($909)	($1,324)	(2.61)	507.9	399.1
$10,821	Winter Mid	1,836	(5.89)	($5,840)	($4,982)	$249	(5.60)	($4,733)	($6,349)	(6.41)	990.9	845.3
			TOTAL	($21,319)	($37,153)	$1,858		($35,295)	($23,176)			
						-5%		-5%	9%			

LOLP (combined)	
2021 GRC	
61.49%	Summer On
1.86%	Summer Mid
4.58%	Summer Off
32.06%	Winter Mid
0.00%	Winter Off
0.00%	Winter Off

100.00%

	PROGRAM	A factor	B factor
1	**BIP 15**	95.50%	100%
2	**BIP 30**	95.50%	100%
3			
4			
5			
6			
7			
8			
9			
10			